DIRECT TESTIMONY OF

JAMES W. NEELY, P.E.

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

DOCKET NO. 2019-184-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Neely and my business address is 220 Operation Way, Cayce, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Dominion Energy South Carolina, Inc. ("DESC" or the "Company")[1] as a Senior Resource Planning Engineer.

Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.

A. I am responsible for modeling DESC's electric system for the purpose of calculating avoided costs, determining the least cost resource plan, forecasting fuel costs, and evaluating changes to electric generation.

[1] South Carolina Electric & Gas Company ("SCE&G") changed its name to Dominion Energy South Carolina, Inc. in April 2019, as a result of the acquisition of SCANA Corporation by Dominion Energy, Inc. For consistency, I use "DESC" to refer to the Company both before and after this name change.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1984 I graduated from Clemson University with a Bachelor of Science degree in electrical engineering. I received a Master of Science degree in management from Southern Wesleyan University in 2002. I received a Bachelor of Science degree from Mars Hill University in 1979. I was employed by SCE&G as a design engineer at V.C. Summer Station from 1992 to 1997. In 1997 I went to work in the SCE&G Resource Planning department as a Resource Planning Engineer. In 2013 I was promoted to Senior Resource Planning Engineer.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the resource plan study that describes the various generation planning scenarios analyzed and to present the resource plan on which avoided energy costs calculations are based.

I also discuss and present the following:

(1) DESC's avoided costs for power purchases under the Public Utility Regulatory Policies Act of 1978 ("PURPA");

(2) the long-run avoided costs for solar qualifying facilities ("QFs") that have production capacity up to 2 megawatts ("MW") and are set forth in the Standard Offer Power Purchase Agreement attached to the direct testimony of Company Witness John E. Folsom as Exhibit No. __ (JEF-2),

(3) the long-run avoided cost for solar QFs with storage that is charged by solar,

(4) the short-run avoided costs for QFs that have power production capacity less than or equal to 100 kilowatts ("kW") and are set forth in Rate Schedule PR-1 attached to Witness Rooks' testimony as Exhibit No. __ (AWR-2), and

(5) the 11 components contained in the net energy metering ("NEM") methodology approved by the Commission in Order No. 2015-194 issued in Docket No. 2014-246-E.

RESOURCE PLAN STUDY

Q. HAS DESC CONDUCTED A RESOURCE PLANNING STUDY?

A. Yes. My department performed a resource study for DESC ("Resource Study"), which is attached as Exhibit No. __ (JWN-1). It shows nineteen resource plans evaluated under four different sets of assumptions, for a total of 76 different scenarios. The Resource Study determined the current resource plan as set forth in the Company's Integrated Resource Plan filed with the Commission on February 8, 2019, and in Table 1 of Exhibit No. ___ (JWN-1).

Q. WHAT SCENARIOS WERE CONSIDERED IN DEVELOPING DESC'S CURRENT RESOURCE PLAN?

A. DESC considered nineteen different resource plans when developing the current resource plan. The resource plans are described in Table 1 below and discussed in more detail in Exhibit No. __ (JWN-1). Please note that "CC" is shorthand for Combined Cycle, "ICT" is shorthand for Internal Combustion Turbine, and "PPA" is shorthand for Power Purchase Agreement. Solar Ownership describes a DESC-owned solar resource.

Table 1

Scenario Number	Resource Plan	Description
1	Battery-1	Ten 100 MW, 400 MWh System Batteries
2	Battery-1 w/ Solar Ownership	Ten 100 MW, 400 MWh system batteries + Ten 100 MW solar generators
3	Battery-2	Ten 100 MW, 400 MWh System Batteries
4	Battery-2 w/ Solar Ownership	Ten 100 MW, 400 MWh system batteries + Ten 100 MW solar generators)
5	CC 1081 MW	One 1-on-1 CC generator
6	CC 540 MW + Retire Coal	One 1-on-1 CC generator with the retirement of a 342 MW coal generator
7	CC 540 MW x2	Two 1-on-1 CC generators
8	CC 540 MW w/ Battery-1	Two 1-on-1 CC generators + One 100 MW, 400 MWh System Battery
9	CC 540 MW w/ Battery-2	Two 1-on-1 CC generators + One 100 MW, 400 MWh System Battery
10	CC 540 MW w/ ICT 337 MW	One 540 MW 1-on-1 CC gas generator + two 337 MW ICT generators
11	CC 540 MW w/ ICT 93 MW	One 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with five 93 MW ICT generators
12	ICT 337 MW	Three 337 MW ICT generators
13	ICT 93 MW	Ten 93 MW ICT generators
14	Solar Ownership w/ ICT 93 MW	Ten 100 MW solar generators + ten 93 MW ICTs
15	Solar Ownership w/ ICT 93 MW + Retire Gas	Ten 100 MW solar generators + fourteen 93 MW ICTs + retirement of 345 MW of gas-fired steam plants
16	Solar PPA 200 MW w/ ICT 93 MW ($30)	200 MWs of solar PPAs with an energy prices of $30/MWh in 2018 and growing at 2% per year + ten 93 MW ICTs
17	Solar PPA 400 MW w/ ICT 93 MW ($30)	400 MWs of solar PPAs with an energy prices of $30/MWh in 2018 and growing at 2% per year + ten 93 MW ICTs
18	Solar PPA 400 MW w/ ICT 93 MW ($35)	400 MWs of solar PPAs with an energy prices of $35/MWh in 2018 and growing at 2% per year + ten 93 MW ICTs
19	Solar PPA 400 MW w/ ICT 93 MW ($40)	400 MWs of solar PPAs with an energy prices of $40/MWh in 2018 and growing at 2% per year + ten 93 MW ICTs

Q. WHAT SENSITIVITIES IN THE ASSUMPTIONS WERE CONSIDERED IN DEVELOPING DESC'S CURRENT RESOURCE PLAN?

A. DESC considered four sets of assumptions when developing the current resource plan: 1) Base Gas Prices with Zero CO_2 Costs, 2) High Gas Prices with \$15/ton CO_2 costs, 3) High Gas Prices with Zero CO_2 Costs, and 4) Base Gas Prices with \$15/ton CO_2 Costs.

Q. HOW WAS THE CURRENT RESOURCE PLAN SELECTED?

A. Base gas prices and zero CO_2 costs were used to select the current plan. Base gas prices is the most likely gas scenario and CO_2 costs are currently zero and future costs are uncertain at this point.

AVOIDED COSTS UNDER PURPA

Q. WHAT DOES PURPA REQUIRE?

A. PURPA and its implementing regulations require electric utilities, including DESC, to purchase electric energy from qualifying facilities ("QF") at the utilities' avoided costs. However, state public utility commissions, such as the Commission, determine the method for calculating avoided costs, which are updated on a periodic basis. The Commission held proceedings in the early 1980s to establish the respective methodologies for determining the avoided costs of each electric utility. Determining a utility's avoided costs using an approved methodology is a process that has been ongoing for decades.

Q. WHAT ARE AVOIDED COSTS?

A. PURPA regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Federal Energy Regulatory Commission ("FERC") further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of* 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). In Order No. 81-214 and subsequent decisions, the Commission has recognized that utilities are entitled to recover their avoided costs under PURPA.

Q. WHAT APPROACH DOES DESC TAKE TO CALCULATE THE ENERGY AND CAPACITY COMPONENTS OF AVOIDED COSTS?

A. As approved by the Commission in Orders No. 2016-297 and 2018-322(A), DESC uses a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and the capacity component of its avoided costs. This approach follows directly from PURPA's definition of avoided costs in that it involves calculating the revenue requirements between a base case and a change case. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed a power purchase agreement. The change case is the same as the base case except that a zero-cost purchase transaction modeled after the appropriate 100 MW energy profile is assumed.

For the avoided energy cost determination a carefully constructed computer program called PROSYM, which models the commitment and dispatch of generating units to serve load hour-by-hour, makes two runs and estimates the production costs and benefits that result from the purchase transaction. The base and change cases are identical except for the zero-cost purchase transaction. The avoided energy cost is the difference between the base case costs and the change case costs.

Q. WHAT PERIOD OF TIME DOES THE COMPANY USE TO CALCULATE ITS AVOIDED COSTS?

A. There are two time periods used to calculate avoided costs. The short-run avoided energy costs are based on one year and calculated for the period May 2019 through April 2020. The long-run avoided energy costs are calculated for calendar years 2020 through 2029. These 10 years are divided into two groups of five years each: 2020-2024, and 2025-2029. Avoided capacity costs uses a 10-year period.

AVOIDED COST RATE FOR THE STANDARD OFFER RATE

Q. DO CERTAIN SOLAR PPAs PROVIDE DESC THE OPPORTUNITY TO RECOVER VARIABLE INTEGRATION COSTS?

A. Yes. There are approximately 700 MWs of PPAs with a Variable Integration Charge ("VIC") clause that allows DESC to recover costs associated with the variable nature of solar. These costs were not captured in the avoided cost calculations filed previously with the Commission.

Q. ARE THERE COSTS TO DESC TO INTEGRATE THE VARIABLE ENERGY SUPPLY FROM SOLAR, AND IS IT POSSIBLE AND APPROPRIATE TO DETERMINE SUCH COSTS FOR THOSE SOLAR GENERATORS OBLIGATED TO PAY THESE COSTS UNDER EXISTING PPAs?

A. Yes and Yes. The Company experiences real and measurable costs to integrate the energy supplied by solar generators due to the variable nature of the supply. In this proceeding Company Witness Dr. Matthew Tanner was employed for the purpose of calculating the Variable Integration Charge ("VIC"). For the benefit of rate payers, we plan to recover these costs from solar generators whose previously signed PPAs include terms allowing recovery of variable integration costs.

Q. IN THIS PROCEEDING IS DESC PROPOSING TO APPLY THE VIC CALCULATED BY DR. TANNER TO NEW PPAs?

A. No. The most appropriate method of addressing issues created by solar intermittency is to model the system with higher operating reserves. The increase in operating reserves is now part of the model and is reflected in our estimated avoided energy costs. Therefore, there is no additional charge included in the avoided costs for integration, however, the Company reserves the right to present in a future proceeding other integration charges that the Company may identify based upon operating experience, study, or analysis.

Q. HAVE YOU MADE ANY OBSERVATIONS REGARDING THE AMOUNT OF RESERVES REQUIRED TO COVER THE INTERMITTENCY OF SOLAR GENERATION?

Yes. We observed that additional reserves equal to 35% of the installed solar capacity is sufficient to cover most of the one-hour solar intermittency. The avoided cost calculations included in this testimony were modeled with additional reserves equal to 35% of the installed solar capacity, during solar generating hours. As more solar is added to the DESC system, these percentages may change and the new operating reserve requirements will be reflected in future avoided cost calculations.

Q. HOW DOES DESC CALCULATE ITS AVOIDED ENERGY COSTS FOR QF FACILITIES TAKING THE COMPANY'S STANDARD OFFER RATE?

A. DESC uses PROSYM to estimate the change in production costs that result from serving the loads in the base case and the change case. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The avoided costs are then accumulated into four time-of-use periods. The change case for solar QFs is derived from the base case by subtracting a 100 MW power purchase modeled after a solar profile. Avoided energy costs are calculated for calendar years 2020 through 2029. These 10 years are divided into two groups of five years each: 2020-2024, and 2025-2029.

Q. HOW DOES DESC CALCULATE ITS AVOIDED CAPACITY COSTS FOR QF FACILITIES TAKING THE COMPANY'S STANDARD OFFER RATE?

A. As previously discussed, DESC takes a similar approach to determining avoided capacity costs as it does with avoided energy costs. Using the DRR methodology approved by the Commission in Order No. 2016-297, DESC calculates the difference in the revenue requirement between the base case and the change case. Using the resource plan in its latest IRP or an updated resource plan if appropriate, DESC calculates the incremental capital investment related revenue required to support the existing resource plan. For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW facility. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan.

Q. WHY IS THIS METHOD REASONABLE?

A. This method identifies adjustments to the utility's expansion plan that are attributable to purchases from QFs. The cost associated with these adjustments is then quantified and accurately reflects the capacity cost benefits that would result from the QF purchase.

Q. USING THIS METHODOLOGY, WHAT ARE THE AVOIDED CAPACITY COSTS FOR THE STANDARD OFFER RATE?

A. The avoided capacity cost for solar QFs subject to the Standard Offer Rate is zero. Incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost.

For non-solar QFs that qualify for the Standard Offer Rate, the avoided capacity cost is $73.46/MWh, but this value only applies for a limited period of time. These avoided capacity rates will be paid during the months of December, January and February for energy generated from 6 am to 9 am. In order to qualify for this credit, the Seller's generation should be fully dispatchable during all of the capacity credit hours identified above.

Q. WHY DOES ADDITIONAL SOLAR CAPACITY NOT AFFECT DESC'S FUTURE CAPACITY NEEDS?

A. DESC performed a study that analyzed the impact of solar on its daily peak demands. This study titled "The Capacity Benefit of Solar QFs 2018 Study," a copy of which is attached to the Direct Testimony of Company Witness Dr. Joseph M. Lynch as Exhibit No. __ (JML-1).

DESC's need for capacity is driven by the winter season. Solar does not help with the capacity need primarily because the winter peak occurs either early in the morning before solar begins to generate energy or in the evening after solar is no longer generating. Because solar does not consistently provide capacity during the winter peak periods, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar is zero.

Q. WHY IS DESC USING A 10-YEAR PERIOD IN ITS EVALUATION OF AVOIDED COSTS?

A. It is important to recognize that projections of future avoided energy costs are uncertain. Therefore, using projected costs beyond the 10-year period required by Act No. 62 would be speculative and could increase the costs paid by DESC's customers.

Q. BASED ON THE COMPANY'S APPROVED METHODOLOGY, WHAT ARE DESC'S AVOIDED COSTS FOR THE STANDARD OFFER RATE?

A. Table 2 below contains the avoided costs for the Standard Offer rate.

Table 2
STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/MWh)

Time Period	Peak Season Peak Hours ($/MWh)	Peak Season Off-Peak Hours ($/MWh)	Off-Peak Season Peak Hours ($/MWh)	Off-Peak Season Off-Peak Hours ($/MWh)
2020-2024	29.09	26.44	29.63	27.26
2025-2029	33.91	29.07	36.75	31.38

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/MWh)

Time Period	($/MWh)
December, January, February 6 am to 9 am	73.46

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/MWh)

Time Period	Annual ($/MWh)
2020-2024	21.26
2025-2029	24.50

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/MWh)

The avoided capacity costs for solar QFs are zero.

Q. HOW WILL DESC ADDRESS AVOIDED COSTS FOR QFs OF GREATER THAN TWO (2) MW?

A. DESC plans to negotiate contracts with any QF greater than 2 MW for which the PR-1 Rate and Standard Offer Rate is not appropriate. The methodology for calculating the avoided capacity and avoided energy will be consistent with the avoided cost methodology outlined previously. The differences lie in using unit specific data to calculate avoided costs. Other specific requirements are described in the Rate PR – Avoided Cost Methodology attached to Company Witness Rooks' testimony as Exhibit No. __ (AWR-5).

AVOIDED COST RATE FOR SOLAR WITH STORAGE

Q. IS DESC PROVIDING A TARIFF FOR SOLAR WITH STORAGE?

A. No. The following discussion provides indicative avoided costs calculations for solar with storage in accordance with Act No. 62, Section 58-41-20(B)(3). The MW requirements for solar with storage would place it in the category of projects above 2 MW that must be negotiated under the terms of Rate PR - Form PPA attached to Company Witness Rooks' testimony as Exhibit No. __ (AWR-7).

Q. HAS DESC CALCULATED AVOIDED COSTS FOR SOLAR WITH STORAGE?

A. Yes.

Q. HOW WAS THE AVOIDED COST CALCULATED?

A. In order to calculate the benefit of solar with storage, two benefits were identified. The first benefit is the energy benefit. The energy benefit is determined by finding the difference in avoided energy cost of one system with 100 MW solar and another system with 100 MW solar and 25 MW storage.

The second benefit is capacity benefit. To calculate the capacity benefit we assumed 100 MW of capacity is added to the system in 2020 which causes a shift of needed resources and their costs. Next we calculate the 10-year levelized change in revenue requirements. This value becomes the capacity benefit in $/kW.

The energy benefit is multiplied times the estimated solar generation to get an annual energy benefit. The levelized capacity benefit is multiplied times the storage capacity kW to get the annual capacity benefit. The sum of these two values divided by 12 months divided by the storage capacity creates the total system benefit for the storage in $/kW per month.

Q. BASED ON THE COMPANY'S METHODOLOGY, WHAT ARE DESC'S AVOIDED COSTS FOR THE SOLAR WITH STORAGE RATE?

A. Table 3 below contains the avoided costs for the solar with storage rate.

Table 3

AVOIDED COST
SOLAR WITH STORAGE

Time Period	Annual ($/MWh)	Annual ($/kWh)	Monthly ($/kW)
2020-2024	21.26	0.02126	3.17
2025-2029	24.50	0.02450	3.17

Q. WHAT ARE THE REQUIREMENTS TO PROVIDE SOLAR WITH STORAGE AND RECEIVE THE SOLAR WITH STORAGE AVOIDED COST?

A. The storage system must initially have a minimum capacity of 15 MW-AC and have the ability to deliver its maximum capacity for four consecutive hours when fully charged. Degradation of the storage system will be specifically addressed in any final contractual arrangements between the provider and DESC. DESC will control the dispatch of the storage.

The fixed monthly payment is intended to compensate the Seller for all aspects of the storage, including, but not limited to, avoided capacity costs and the dispatch rights associated with the discharge of the storage system.

PR-1 RATE

Q. HOW DOES DESC COMPUTE THE AVOIDED ENERGY COMPONENT FOR SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. DESC uses the same methodology to estimate avoided energy costs for solar QFs on PR-1 as it did for solar QFs in the Standard Offer Rate. The only difference is the time period over which the avoided energy costs are estimated. The short-run avoided energy costs in the PR-1 Rate are calculated for the period May 2019 through April 2020 whereas the Standard Offer Rate is a 10-year calculation. Losses for PR-1 are also different. Losses for PR-1 are on calculated at the primary distribution level.

Q. HOW DOES DESC COMPUTE THE AVOIDED ENERGY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. As discussed previously, DESC uses PROSYM to estimate the change in production costs that result from serving the base case load and the change case. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The avoided costs are then accumulated into four time-of-use periods set forth in Table 4. A non-solar QF would be paid based on how much energy it produces in each of these four time-of-use periods.

Q. HOW DOES DESC COMPUTE THE AVOIDED CAPACITY COMPONENT FOR SOLAR AND NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. DESC takes a similar approach to determining avoided capacity costs as it does with avoided energy costs. Using the DRR methodology approved by the Commission in Order No. 2016-297, DESC calculates the difference in the revenue requirement between the base case and the change case. Using the resource plan in its latest IRP or an updated resource plan if appropriate, DESC calculates the incremental capital investment related revenue required to support the existing resource plan. As with its calculation of avoided energy costs, DESC derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW facility. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan.

Q. WHAT IS THE AVOIDED CAPACITY COST COMPONENT FOR QFs IN THE PR-1 RATE?

A. The avoided capacity cost for solar QFs subject to the PR-1 Rate is zero. Incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost.

For non-solar QFs that qualify for the PR-1 Rate, the avoided capacity cost is $0.07346/kWh. It will be paid during the months of December, January and February for energy generated from 6 am to 9 am. The capacity payment is available only to generators capable of providing power in all of the identified hours.

Q. WHAT ADJUSTMENTS ARE MADE TO THE AVOIDED COSTS IN THE PR-1 RATE?

A. The avoided energy cost results for both solar QFs and non-solar QFs are adjusted for line losses, working capital impacts, gross receipts taxes, and generation taxes.

Q. WHAT IS THE RESULTING PR-1 RATE?

A. The avoided costs are shown in Table 4 below.

Table 4

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
May 2019-April 2020	0.02843	0.02738	0.03508	0.03364

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 am to 9 am	0.07346

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
May 2019-April 2020	0.03149

PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

The avoided capacity costs for solar QFs are zero.

<u>COMPONENTS OF VALUE FOR</u>
<u>NET ENERGY METERING DISTRIBUTED ENERGY RESOURCES</u>

Q. WHAT ARE THE COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES?

A. By way of its Order No. 2015-194 issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

Net Energy Metering Methodology

1. +/- Avoided Energy
2. +/- Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided CO_2 Emission Cost
8. +/- Fuel Hedge
9. +/- Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

= Total Value of NEM Distributed Energy Resources

Q. HAS DESC UPDATED THESE COMPONENTS OF VALUE?

A. Yes. Table 5 shows the updated components of value for NEM Distributed Energy Resources. Two columns of numbers are shown: one for the current value and one for the value over the 10 year planning period. The difference between these two columns of numbers represents the future benefits of DER and are subject to recovery under S.C. Code Ann. § 58-40-20(F)(6).

Table 5
Total Value of NEM Distributed Energy Resources ($/kWh)

	Current Period ($/kWh)	10-Year Levelized ($/kWh)	Components
1	0.03053	$0.02210	Avoided Energy Costs
2	$0.0	$0.0	Avoided Capacity Costs
3	$0.0	$0.0	Ancillary Services
4	$0.0	$0.0	T & D Capacity
5	$0.00003	$0.00003	Avoided Criteria Pollutants
6	$0.0	$0.0	Avoided CO_2 Emission Cost
7	$0.0	$0.0	Fuel Hedge
8	$0.0	$0.0	Utility Integration & Interconnection Costs
9	$0.0	$0.0	Utility Administration Costs
10	$0.00093	$0.00116	Environmental Costs
11	$0.03149	$0.02329	Subtotal
12	$0.00257	$0.00190	Line Losses @ 0.9245
13	$0.03406	$0.02519	**Total Value of NEM Distributed Energy Resources**

Q. PLEASE EXPLAIN THE COMPONENTS OF VALUE FOR AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS SHOWN ON LINE NOS. 1 AND 2 OF TABLE 5.

A. The components of value for avoided energy costs and avoided capacity costs are based on the PURPA avoided cost values previously discussed with one adjustment. The avoided energy costs are adjusted to remove the cost of criteria pollutants and environmental costs, which are then reflected in the components shown on Lines 5 and 10, i.e., Avoided Criteria Pollutants and Environmental Costs. Both the avoided energy costs and the avoided capacity costs are based on solar QFs.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ANCILLARY SERVICES SHOWN ON LINE NO. 3 OF TABLE 5.

A. Ancillary services refer to the need to balance the load and generation on the system and include operating reserves, both spinning and non-spinning; frequency regulation; and voltage control. We observed that additional operating reserves equal to 35% of the installed solar capacity covers most of the one-hour solar intermittency. These additional reserves create a net reduction in the avoided energy costs, but because of the difficulty of splitting out the portion of avoided costs due to increased reserves we left it in the avoided energy value.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR TRANSMISSION AND DISTRIBUTION CAPACITY SHOWN ON LINE NO. 4 OF TABLE 5.

A. DESC's NEM distributed resources do not avoid transmission or distribution capacity and therefore the value of this component is zero. On DESC's transmission system, customer-scale NEM resources are distributed across DESC's transmission system and have too small of an impact on any transmission circuit to result in avoided transmission capacity. For example, the most impacted substation currently on DESC's system is connected to 1,818 kW of solar capacity owned by 257 customers. The impact of a 1,818 kW change in load is much too small to affect the planning of our need for a 115 kV or a 230 kV circuit, which carry loads between 237,000 and 948,000 kW.

On the distribution system, DESC's engineers must design a circuit for circumstances that will stress the circuit. In particular, since solar output is intermittent during the day and non-existent at night, they must also plan for when the DER is not supplying power. The distribution line must carry the load both when the DER is generating and when it is not because of weather-related factors or because DER resources are off line.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CRITERIA POLLUTANTS SHOWN ON LINE NO. 5 OF TABLE 5.

A. DESC associates a positive avoided cost value to criteria pollutants NO_x and SO_2. The avoided cost of these pollutants typically is included in the Company's avoided energy costs but, these costs have been separated out in this proceeding for reporting purposes.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CO_2 POLLUTANTS SHOWN ON LINE NO. 6 OF TABLE 5.

A. Pursuant to Commission Order No. 2015-194, the component of value for avoided CO_2 is set at zero until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions. Currently, there are no state or federal laws or regulations restricting the emission of CO_2 pollutants and, therefore, the value for CO_2 pollutants is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR FUEL HEDGE SHOWN ON LINE NO. 7 OF TABLE 5.

A. DESC does not hedge fuels for electric generation. Therefore, the value for fuel hedging is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY INTEGRATION & INTERCONNECTION COSTS SHOWN ON LINE NO. 8 OF TABLE 5.

A. There is no additional charge included on Line No. 8 of Table 5 for utility integration and interconnection costs. Other integration and interconnection costs of NEM Distributed Energy Resources are being collected through a DER rider added to the fuel clause. Therefore, the value of this component is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY ADMINISTRATION COSTS SHOWN ON LINE NO. 9 OF TABLE 5.

A. At present, the administration costs of NEM Distributed Energy Resources are being collected through a DER rider being added to the fuel clause. Therefore, the value of this component is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENVIRONMENTAL COSTS SHOWN ON LINE NO. 10 OF TABLE 5.

A. The component of "Environmental Costs" refers to any appropriate environmentally related costs that were not already included in other net metering methodology components. DESC associates a positive avoided cost value to represent the cost of certain environmental materials used in the generation of energy, such as lime and ammonia. The avoided cost of these materials typically is included in the Company's avoided energy costs but these costs have been separated out in this proceeding for reporting purposes.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENERGY LOSSES/LINE LOSSES SHOWN ON LINE NO. 11 OF TABLE 5.

A. When a NEM Distributed Energy Resource serves a customer's load behind their meter or when it puts power onto the distribution system, DESC avoids having to generate that specific amount of energy. The Company also avoids the energy required to bring the power to the customer's meter or the distribution system, i.e.

the line losses associated with delivering power across the system. The loss factor used for these NEM values represents the cumulative marginal line losses at a residential customer's meter.

CONCLUSION

Q. WHAT IS DESC REQUESTING OF THE COMMISSION IN THIS PROCEEDING?

A. DESC respectfully requests that the Commission approve the calculation of the total value of NEM Distributed Energy Resources as set forth in my testimony, the proposed PR-1 avoided costs, Standard Offer avoided costs, and the avoided cost methodology to be used for future updates to the Standard Offer and for calculation of the avoided costs for small power producers which do not qualify for the Standard Offer PPA.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Resource Study

Introduction

The following pages documents a study that was performed to assess the cost of generation that could meet the resource plan needs of Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") electric system. In each case, generation is added over a thirty-year horizon then modeled using DESC's hourly dispatch model. Costs are extrapolated for another ten years then the scenarios are compared using the scenario's 40-year levelized net present value. Generation is added to meet the winter base reserve level.

Reserve Margin

DESC's reserve margin policy is summarized in the following table. Peaking reserves are considered the capacity needed during the five highest peak load days in the season while base reserves are needed for the balance of the season.

DESC's Reserve Margin Policy		
	Summer	Winter
Base Reserves	12%	14%
Peaking Reserves	14%	21%
Increment for Peaking	2%	7%

DESC's generating resources serve both the base capacity need and the peak capacity need.

	Base MW Need		Peak MW Need	
Year	Summer	Winter	Summer	Winter
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	3
2023	0	0	0	30
2024	0	0	0	77
2025	0	0	0	128
2026	0	0	0	182
2027	0	0	0	229
2028	0	5	0	271
2029	0	51	0	274
2030	0	99	0	276
2031	0	147	0	279
2032	0	194	0	281
2033	45	242	0	284
2034	93	287	0	286
2035	141	332	0	288
2036	188	377	0	291
2037	235	425	0	293

These results show that the winter season requires more of both base and peak capacity needs than does the summer season. In fact, with respect to the need for base capacity, the capacity added to meet the winter base capacity need will also serve to meet the summer base capacity need. Furthermore, there is no need for additional summer peaking resources. The derivation of these results is shown later in this report or in the appendix.

Meeting the Base Resource Need

For base resources, the winter base reserve margin of 14% was used to determine the timing of adding generation resources. DESC created a list of 8 generating resources to be considered, which are reflected in the table below. Please note that "CC" is shorthand for Combined Cycle, "ICT" is shorthand for Internal Combustion Turbine, and "PPA" is shorthand for Power Purchase Agreement.

Resource	Capital Cost 2017$/kW	Description
Battery #1	$2,126	100 MW with 400 MWH
Battery #2	$1,350	100 MW with 400 MWH, $1.65 MM/year in O&M
Solar Farm	$1,762	
CC 2-on-1	$876	1,081 MW with HR=6,203
CC 1-on-1	$938	540 MW with HR=6,276
ICT#1	$647	337 MW with HR=9,091
ICT#2	$697	93 MW with HR=9,169
Solar PPA	N/A	$30, $35, $40/MWh in 2018 esc. @2%

These 8 resources were combined in various ways to develop 19 resource plans, some of which consider the retirement of certain existing generating units. The 19 scenarios are listed in the following table followed by a description of each scenario.

Scenario Number	Scenario
1	Battery-1
2	Battery-1 w/ Solar Ownership
3	Battery-2
4	Battery-2 w/ Solar Ownership
5	CC 1,081 MW
6	CC 540 MW + Retire Coal
7	CC 540 MW x 2
8	CC 540 MW w/ Battery-1
9	CC 540 MW w/ Battery-2
10	CC 540 MW w/ ICT 337 MW
11	CC 540 MW w/ ICT 93 MW
12	ICT 337 MW
13	ICT 93 MW
14	Solar Ownership w/ ICT 93 MW
15	Solar Ownership w/ ICT 93 MW + Retire Gas
16	Solar PPA 200 MW w/ ICT 93 MW, $30/MWh
17	Solar PPA 400 MW w/ ICT 93 MW, $30/MWh
18	Solar PPA 400 MW w/ ICT 93 MW, $35/MWh
19	Solar PPA 400 MW w/ ICT 93 MW, $40/MWh

Scenario 1: In this scenario, 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 2: In this scenario, 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $2,126/kW ($2017) with no annual cost. In this scenario, 1,000 MW of solar generation is also added between 2028 and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 3: In this scenario, 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year.

Scenario 4: In this scenario, 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year. In this scenario, 1,000 MW of solar generation is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 5: In this scenario, one 1,081 MW 2-on-1 combined cycle (CC) gas generating plant is added in the winter of 2029. This combined cycle generator has a full load heat rate of 6,203 Btu/kWh and an estimated construction cost of $876/kW ($2017).

Scenario 6: In this scenario, three 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winter of 2029, 2033 and 2044. This scenario also includes the retirement of one 342 MW coal plant in the winter of 2029. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 7: In this scenario, two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2029 and the winter of 2040. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 8: In this scenario, 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 9: In this scenario, 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW with an annual cost of $1.65M per year.

Scenario 10: In this scenario, one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with two 337 MW ICT generators added in the winters of 2040 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 337 MW turbines have a full load heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 11: In this scenario, one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with five 93 MW ICT generators added in the winters of 2040, 2042, 2044, 2046 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 12: In this scenario, three 337 MW internal combustion turbines (ICT) are added in the winters of 2029, 2036 and 2043. These turbines have a full load winter heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 13: In this scenario, ten 93 MW internal combustion turbines (ICT) are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 14: In this scenario, 1,000 MW of solar generation and 930 MW of ICTs are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 15: In this scenario, 1,000 MW of solar generation and 1,302 MW of ICT are added in years 2028(4), 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2046. Three gas-fired steam plants are retired in the winter of 2028 with a combined capacity of 346 MW. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 16: In this scenario, 200 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are prices at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 17: In this scenario, 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 18: In this scenario, 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $35/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 19: In this scenario, 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are priced at $40/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Sensitivities and Results

The incremental revenue requirements associated with each of the 19 resource plans was computed using the PROSYM computer program to estimate production costs and an EXCEL capital model to calculate the associated capital costs. The EXCEL capital model combined the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon. Four sensitivities were considered: two on natural gas prices and two on the cost of CO_2 emissions. The four assumptions are: 1) $0/ton CO_2 and base gas prices, 2) $15/ton CO_2 and high gas prices, 3) $0/ton CO_2 and high gas prices, and 4) $15/ton CO_2 and base gas prices. Base gas prices are based on NYMEX Henry Hub prices through 2020 then growing at 4.82% until 2031 then growing at 3.9% thereafter. High gas prices are double the base gas prices. The following table shows the ranking of each resource plan under each sensitivity. A ranking of 1 is the least-cost option for the given assumptions.

		Scenario Ranking			
Scenario Number	**Scenario**	**$0 CO_2 Base gas**	**$15 CO_2 High gas**	**$0 CO_2 High gas**	**$15 CO_2 Base gas**
1	Battery-1	16	17	16	17
2	Battery-1 w/ Solar Ownership	19	18	19	19
3	Battery-2	11	13	12	15
4	Battery-2 w/ Solar Ownership	18	16	15	18
5	CC 1081 MW	14	14	14	11
6	CC 540 MW + Retire Coal	12	15	17	4
7	CC 540 MW x2	1	10	10	6
8	CC 540 MW w/ Battery-1	17	19	18	16
9	CC 540 MW w/ Battery-2	13	12	13	13
10	CC 540 MW w/ ICT 337 MW	8	9	8	8
11	CC 540 MW w/ ICT 93 MW	6	7	6	2
12	ICT 337 MW	9	11	9	10
13	ICT 93 MW	2	5	5	7
14	Solar Ownership w/ ICT 93 MW	10	6	7	12
15	Solar Ownership w/ ICT 93 MW + Retire Gas	15	8	11	14
16	Solar PPA 200 MW w/ ICT 93 MW ($30)	3	4	3	3
17	Solar PPA 400 MW w/ ICT 93 MW ($30)	4	1	1	1
18	Solar PPA 400 MW w/ ICT 93 MW ($35)	5	2	2	5
19	Solar PPA 400 MW w/ ICT 93 MW ($40)	7	3	4	9

Resource scenario #7 is the lowest-cost resource plan under the assumption of $0 per ton of CO_2 emission and base gas costs. Scenario #17 is the lowest-cost resource plan under the other three sensitivities. Because base gas prices is the most likely gas scenario and CO_2 costs are uncertain at this point, resource scenario #7 is the resource plan used in developing avoided costs and forecasting fuel costs.

Some Observations

The results above do not reflect a decision on the Company's part but only represent a snapshot at the present time and offer possible expansion plans under different sensitivities. More work on this issue will be done and based on additional peak demand forecasts as they are updated. However, it is helpful to make some observations about these results to extract as much useful information as possible from the study. For example, under the $0 per ton CO_2 cost and base gas price scenario, resource plan #7 was the most economical. Cheaper energy provided by a new, highly efficient combined cycle plant when gas prices are relatively low without CO_2 emission costs offers enough economic benefit to overcome the extra capital costs.

Resource plan #13 is more economical than #12 under all four sensitivities, suggesting that using the smaller ICT of 93 MW is better than using the larger ICT even though there is a higher capital cost and heat rate cost. The same conclusion can be drawn when comparing resource plan #11 to #10. Another possibility to consider in future studies involves the early retirement of coal units. Resource plan #6 falls fourth in the ranking when there is a $15 CO_2 emissions cost coupled with low gas prices. If gas prices were a little lower with respect to coal prices and the cost of CO_2 emissions a little larger, the retirement of coal units might prove to be an economical option.

Adding 100 MW batteries is consistently more expensive than adding 93 MW peaking facilities, which can be seen by comparing scenario #11 with #9 and scenario #14 with #4.

Resource scenario #17 was the most economical in three of the four sensitivities considered, i.e., whenever the gas price was high or there was a CO_2 emissions cost, the clean energy provided by more solar proved valuable to the system. However, this option presents two significant questions: 1) can solar energy be purchased at $30 per MWh escalating at 2% and 2) can the system dispatch address the increase in operating issues caused by adding another 400 MW of solar to a system already dealing with over 1,000 MW of solar? As the system cost increases for solar PPA this scenario moves out of the least cost position, as seen in scenarios 18 and 19. DESC will continue to evaluate these and other scenarios in the future.

Meeting the Peak Resource Need

For peak resources, the winter incremental peak reserve margin of 7% was used. The Company does not require any more summer peak capacity in large part because of all the solar energy currently on the system or under contract. Peak capacity is capacity needed to supplement base capacity on the five highest load days in the season. As was just discussed, the Company does not need additional base capacity until 2029 so until then there is extra base capacity to support the peak needs. With approximately 100 MW of demand response for peaking needs, significant additional peak capacity is not required until 2023 or 2024. At present the Company is conducting a DSM Potential Study which will include demand response options for winter. When this study is complete, the Company will be able to identify the best way to meet its winter peaking needs.

APPENDIX

Table 1. Resource Scenario #7

		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
	SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update (MW)																														
	YEAR	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	6295	6463	6295	6463	6295	6463	6295	6463
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0																								
8	Peaking/Intermediate																						540								
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6488	6144	6489	6145	6491	6146	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
12	Winter Deficit		0		0		0		3		30		77		128		182		229		277		0		0		0		0		0
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6488	6326	6489	6374	6491	6423	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1318	1098	1276	1106	1234	1115	1195	1339	1693	1297	1652	1255	1609	1215	1569	1173
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	25.5%	21.0%	24.5%	21.0%	23.5%	21.0%	22.6%	25.0%	31.7%	24.1%	30.7%	23.1%	29.7%	22.2%	28.7%	21.3%

Table 2. Resource Scenario #17

SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update
(MW)

	YEAR	2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5848	6016	5848	6016	5941	6109	5941	6109
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	482	184	482	184	482	184	482	184	482	184	482	184	482	184
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0										184														
8	Peaking/Intermediate																						93				93				93
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6488	6328	6489	6329	6491	6330	6492	6424	6586	6425	6587	6519	6681	6520	6682	6614
12	Winter Deficit		0		0		0		3		30		77		128		0		45		93		47		98		56		105		63
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6488	6328	6489	6374	6491	6423	6492	6471	6586	6523	6587	6575	6681	6625	6682	6677
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1318	1100	1276	1106	1234	1115	1195	1123	1246	1132	1205	1141	1255	1150	1215	1159
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	25.5%	21.0%	24.5%	21.0%	23.5%	21.0%	22.6%	21.0%	23.3%	21.0%	22.4%	21.0%	23.1%	21.0%	22.2%	21.0%